New England Overview: A Primer on Natural Gas Related Issues in 2018

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BOSTON Green Ribbon COMMISSION

RAAB ASSOCIATES

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1. Introduction

Natural gas continues to be an issue of great interest and significant controversy throughout New England. Proponents of building additional gas pipeline infrastructure to secure additional natural gas supply into New England maintain that doing so will reduce gas prices and electricity prices (since approximately half of the region's generation fleet is now gas-fired). They further argue that additional pipelines will enhance the reliability of the region's electricity system. Opponents of additional gas pipeline infrastructure and supply maintain that increasing reliance on natural gas will delay the achievement of the region's long-term climate reduction obligations (i.e., 80 percent reduction by 2050) and create stranded costs. This primer does not take a position on this regional debate, but it does provide an up-to-date discussion of this multi-faceted and complex set of facts and issues.

This primer is an update of a paper provided to the Green Ribbon Commission three years ago: ***A Primer on Large-Scale Energy Infrastructure Issues in 2015—New England Overview*** (April 30, 2015).[1] Updates to all of the tables and figures (and related text) are provided where changes have occurred and data was readily available. This covers topics related to both the supply and consumption of natural gas in New England. Moreover, this primer includes an entire new section on **Major Recent Gas-Related Developments in Massachusetts and New England**. This includes: (1) important new studies; (2) policies and programs related to potentially supporting new gas pipelines and supply; (3) pipeline project completions and cancellations; (4) renewable energy related developments; and (5) developments related to electricity supply and generation that impact gas issues in the near and long term.

2. Natural Gas Supply and Demand Overview

2.1. Appalachian Gas Effect

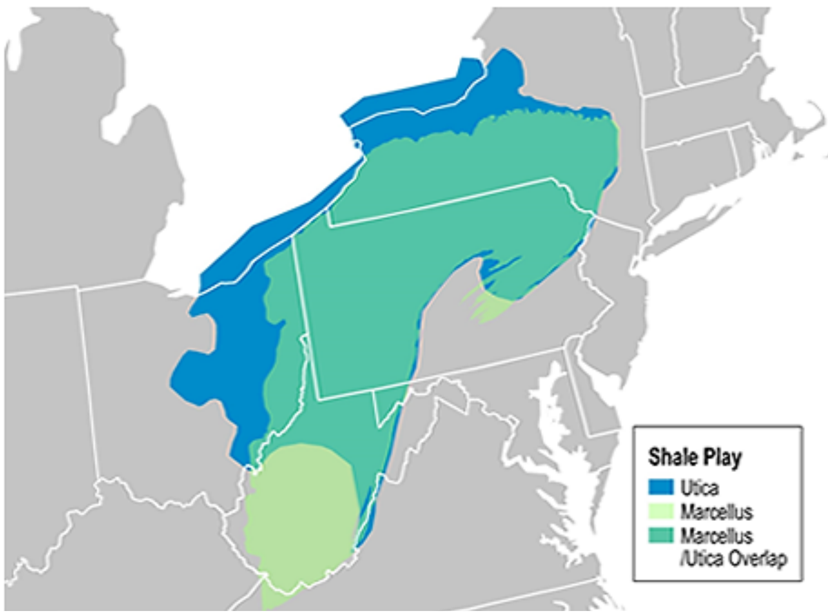
Natural gas has become the dominant fuel in New England over the past decade as gas prices have fallen due to increasing U.S. gas production. The increased production is a result of new drilling techniques (fracking and horizontal drilling), most notably from the Marcellus and Utica Shale (See Figure 1) in and around Pennsylvania, Ohio, and West Virginia (collectively now referred to as Appalachian Shale). The current production there of around 28 billion cubic feet (Bcf) of natural gas per day is sharply increased from only

[1] The original primer covered both electricity and gas issues and was co-authored by Dr. Jonathan Raab, Raab Associates and Paul Peterson, Synapse Energy Economics. This updated primer was authored solely by Dr. Raab with selected input and insights from Stephen Leahy of Northeast Gas Association and from Synapse Energy Economics.

1.5 Bcf a decade ago and 11 Bcf just five years ago (See Figure 2). This is more than 10 times New England's total average daily natural gas consumption for all end-uses of approximately 2.5 Bcf/day.

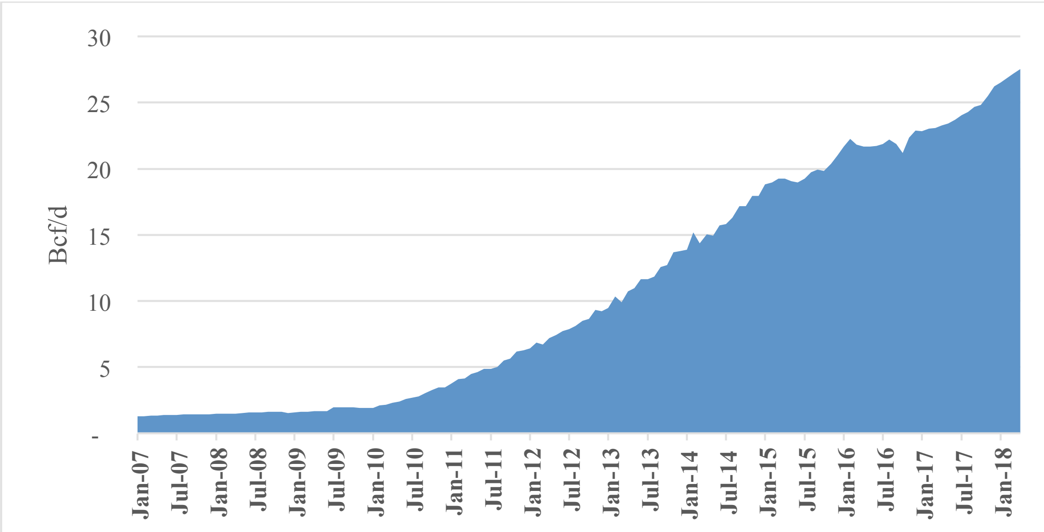
During this period, as natural gas prices declined, natural gas utilization in New England increased in both the electricity and home heating sectors. Natural gas is now responsible for approximately 50 percent of electricity generation in New England—up from only 10-15 percent a mere decade ago. Home heating has also seen a large uptick in New England—everywhere that natural gas is available (i.e., from natural gas distribution pipelines). Natural gas now comprises approximately 30 percent of all primary energy consumed for all sectors in New England.

Figure 1. Appalachian shale locations (Marcellus and Utica)



Source: U.S. Energy Information Administration.

Figure 2. Appalachian production 2007-2018, Bcf/

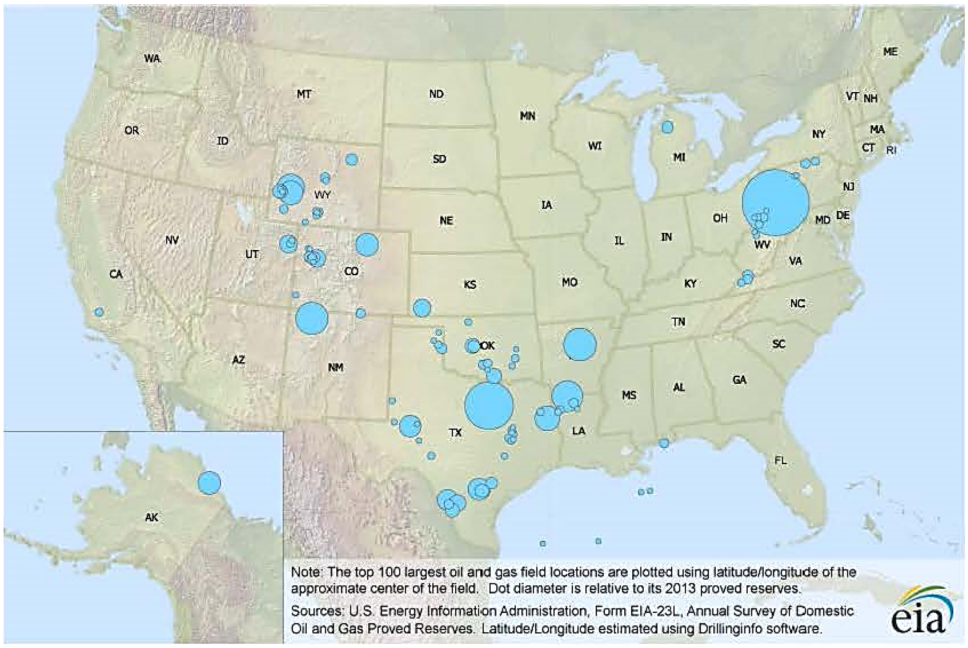


Source: U.S. Energy Information Administration, "Drilling Productivity Report."

2.2. Changing Northeast Gas Supply Dynamic

New England traditionally has been considered "at the end of the pipeline" and constrained on delivery points for pipeline gas. Historically, its gas supplies came predominantly from the U.S. Gulf Coast, western Canada, offshore eastern Canada, and imported liquified natural gas (LNG). Pipeline gas typically accounts for more than 90 percent of supply and LNG less than 10 percent. The advent of Appalachian shale gas development starting around 2007 changed the entire regional supply dynamic. Appalachian shale gas is now ranked as having the largest gas resource potential in the United States (See Figure 3). In recent years, output has been increasing and prices are relatively low—even in New England. The current focus in the Appalachian production area is on the development of pipeline infrastructure to get the produced gas to market—whether the Northeast, southern United States, or potentially for export.

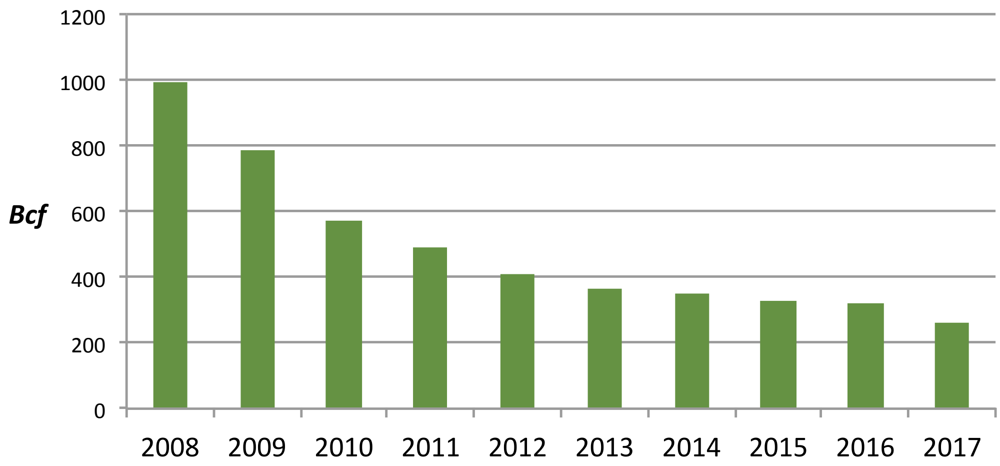
Figure 3. Top 100 U.S. natural gas fields by reserves



Source: U.S. EIA's gas resource map, April 2015.

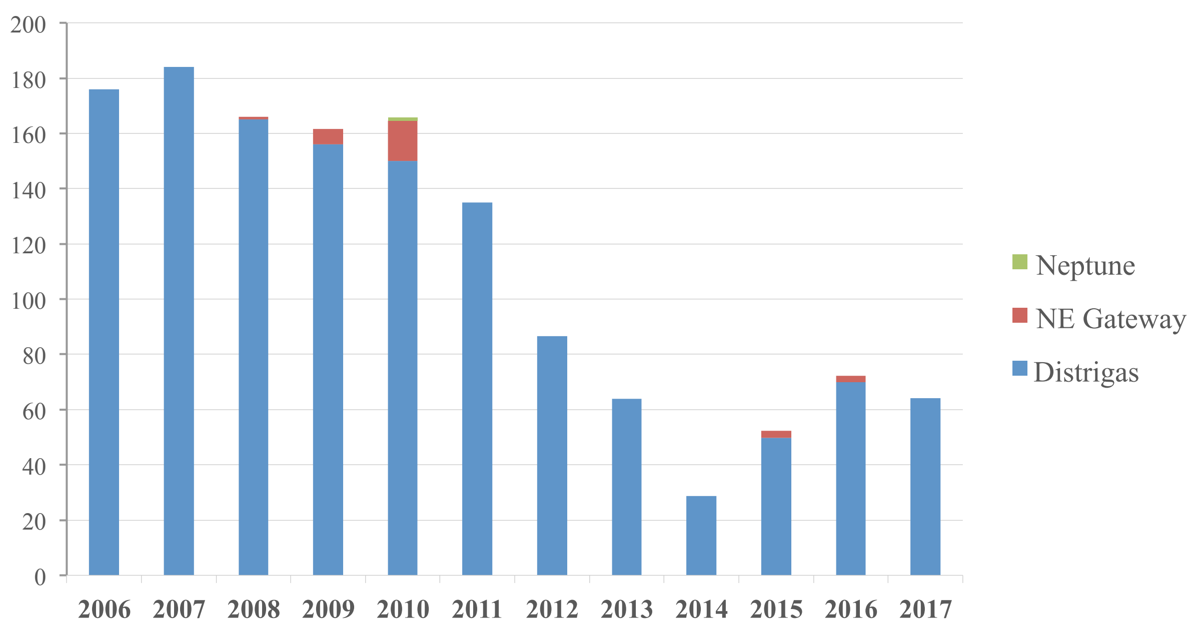
For New England, the pipelines to the "west" (i.e., New York and Pennsylvania) are essentially full as more and more of the market seeks to source its gas from Appalachia. At the same time, Canadian pipeline gas imports (now relatively expensive compared to Appalachian shale gas) have dropped fairly dramatically in recent years (Figure 4). Liquefied natural gas (LNG) imports also dropped dramatically between 2006 and 2017 for the same reason, with a small but significant uptick in 2015–2017 as LNG was called into service in cold winter months to provide gas to electric generators when pipeline gas was unavailable (Figure 5). The Canadian pipelines and LNG import facilities are increasingly underutilized. At the same time, pipeline proposals to increase delivery capacity from the "west" end of the region into New England continue to be discussed.

Figure 4. Canadian natural gas export to eastern United States, 2008–2017



Source: National Energy Board, Canada.

Figure 5. LNG imports to New England terminals, 2006–2017 (Bcf/year)

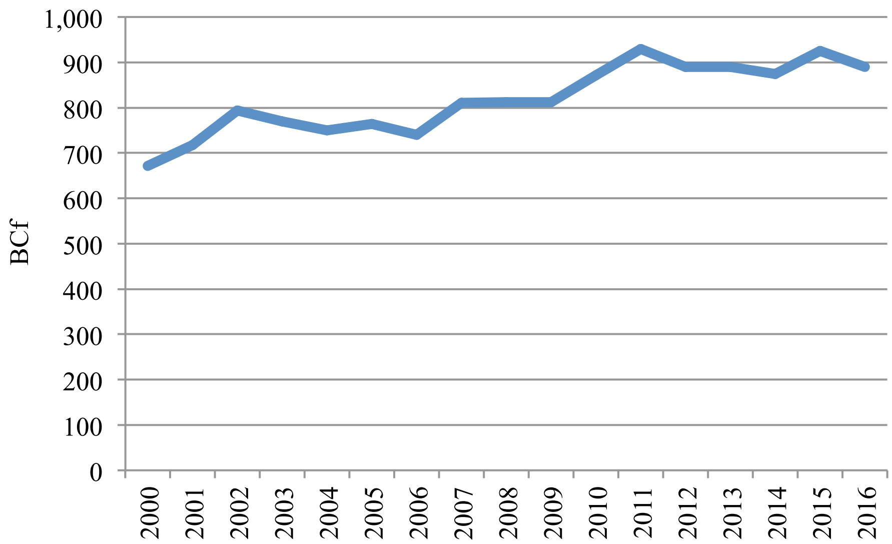


Source: Northeast Gas Association. "The Role of LNG in the Northeast Natural Gas (and Energy) Market). Available at: http://www.northeastgas.org/about_lng.php*. Accessed May 17, 2018.*

2.3. Gas Demand

As shown in Figure 6, annual natural gas demand in New England rose nearly 40 percent over an 11-year period (2000–2011). Since 2011, overall gas demand has been relatively flat to slightly declining due to numerous factors including pipeline constraints and aggressive gas and electric energy efficiency programs.

Figure 6. New England annual gas consumption 2000-2016 (Bcf)



Source EIA Natural Gas Data.

Of the natural gas used in New England in 2017, as Table 1 shows, 42 percent was in electricity generation, 23 percent was in the residential sector (largely for space and water heating), 23 percent was in the commercial sector (also largely for heating), and 12 percent was in the industrial sector. Approximately half of the gas in New England was used in Massachusetts, a little more than one-quarter in Connecticut, and a little less than a quarter in the other four New England states.

Table 1. New England natural gas consumption: By state & by sector (2017 in BCF/Year)

	Residential	Commercial	Industrial	Electric Power	Total	Percent by State
Connecticut	49	53	25	107	234	27%
Maine	3	9	17	22	52	6%
Massachusetts	122	114	46	163	445	51%
New Hampshire	8	10	9	26	52	6%
Rhode Island	19	12	8	47	86	10%
Vermont	4	6	2	0	12	1%
New England	204	204	107	366	881	100%
Percent End Use	23%	23%	12%	42%	100%	

Source: Developed by Raab Associates using EIA Natural Gas Data. Note a few cells are from 2016 when 2017 data not yet available. Also does not include relatively small amounts of natural gas used in transportation and pipeline/distribution use.

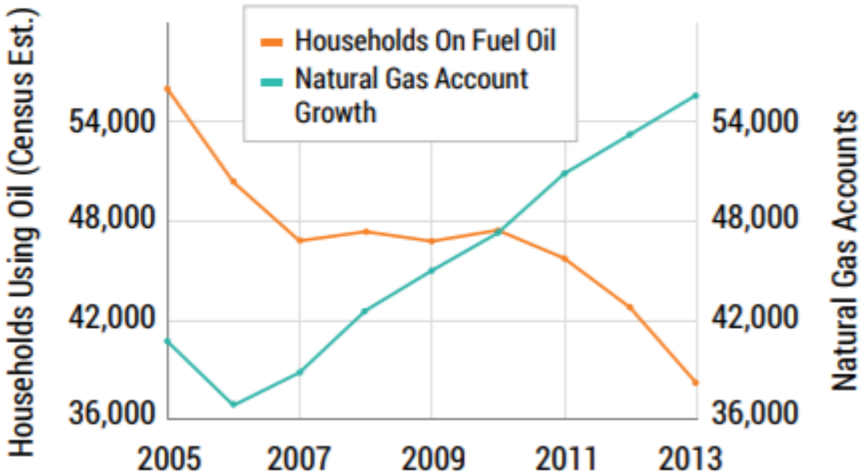
In Massachusetts, 52 percent of households heat with natural gas as their primary fuel source. This is higher than New England as a whole (at 39 percent) due to a lack of transmission and distribution pipeline infrastructure in other New England states (see Table 2). In Boston alone, home heating with natural gas increased from around 36,000 homes in 2006 to 54,000 homes in 2013—a 50 percent increase in only seven years (see Figure 7).

Table 2. Primary fuel home heating households New England and Massachusetts 2016

	New England		Massachusetts	
Fuel	Number	Percent	Number	Percent
Natural Gas	2,229,701	39%	1,332,610	52%
Fuel Oil	2,035,136	36%	688,925	27%
Electricity	775,626	14%	405,055	16%
Propane	325,168	6%	81,858	3%
Other Fuels	286,429	5%	70,950	3%
Total	5,652,060	100%	2,579,398	100%

Source: U.S. Census Bureau.

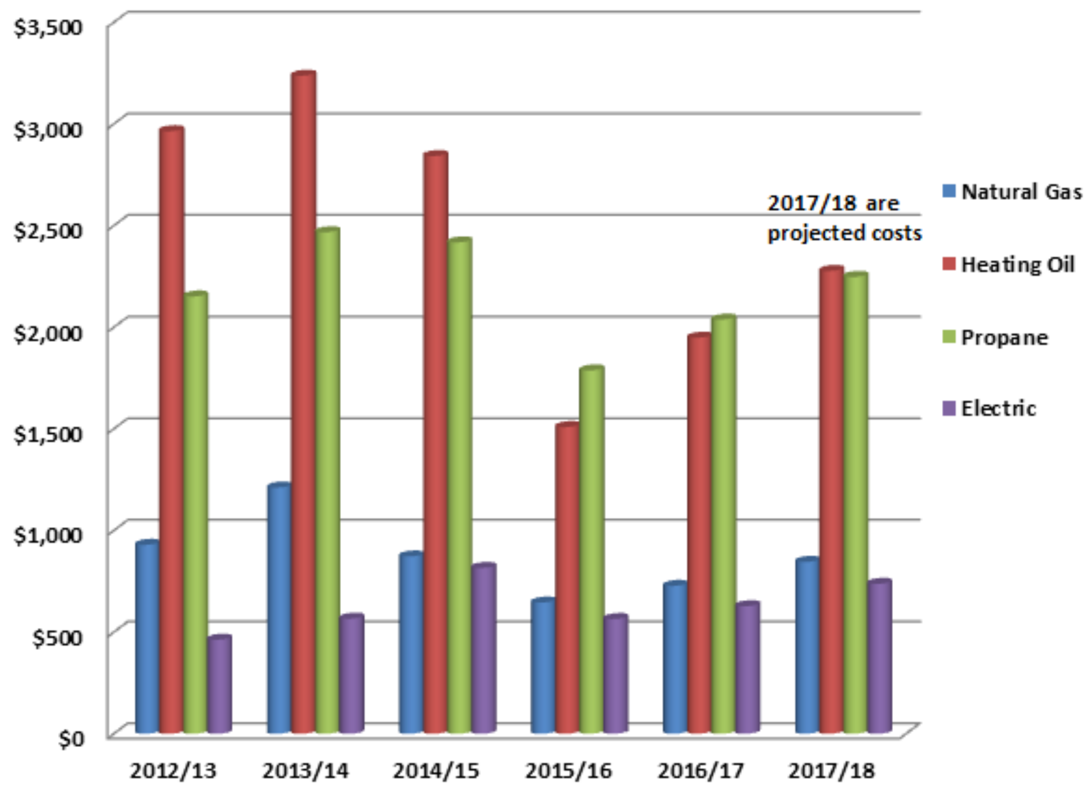
Figure 7. Boston household natural gas and oil heating, 2005–2013



Source: Greenovate Boston 2014 Climate Action Plan Update.

A primary motivating factor for home heating customers to convert to natural gas has been the relative fuel costs between natural gas and other options. As Figure 8 shows, heating with natural gas or electricity has been less than half the cost of heating with propane or oil for some time now in Massachusetts.

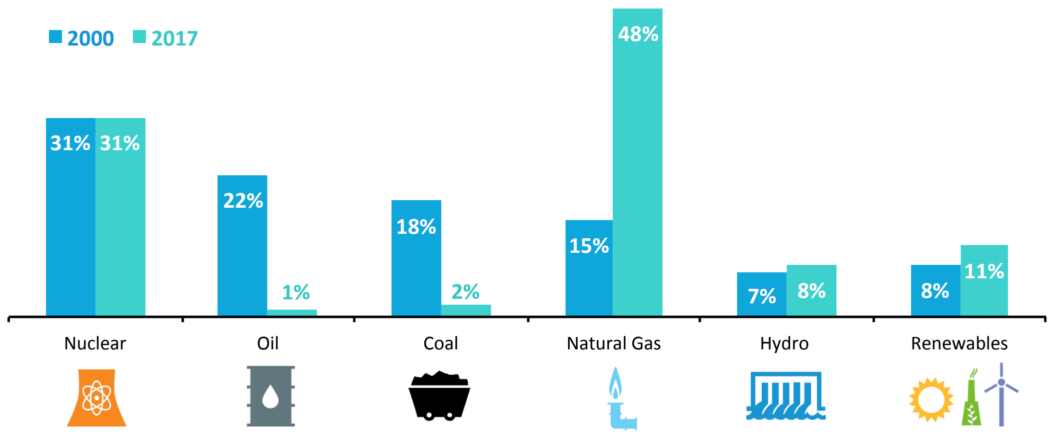
Figure 8. Heating costs by fuel type in Massachusetts



Source: U.S. DOE/EIA; Mass. Utility Filings, DOER State Heating Oil and Program Pricing (SHOPP) surveys. Estimated average heating bills by fuel, 2012/13 to 2017/18.

Perhaps the most dramatic increase in gas use in New England over the past two decades has been in the electricity generation sector. In 2000, gas-fired generation accounted for only 15 percent of the generation in the region. But by 2017, gas-fired generation accounted for nearly half of the generation in New England (Figure 9). Electric generators typically purchase gas from the spot market or through short-term contracts as it becomes available from the local gas distribution companies (LDCs) that have firm contracts for nearly all of their gas supply to ensure that heating customers have access to gas during cold periods. The region's heavy dependence on natural gas leads to various challenges for the region on the coldest winter days. On these days, heating customers use the vast majority of pipeline gas. This leaves less supply available for gas-fired electricity generation and results in higher prices on the spot market causing some generators to turn to other fuels like oil during the coldest periods or not run at all.

Figure 9. New England electricity generation resources: 2000 compared to 2017



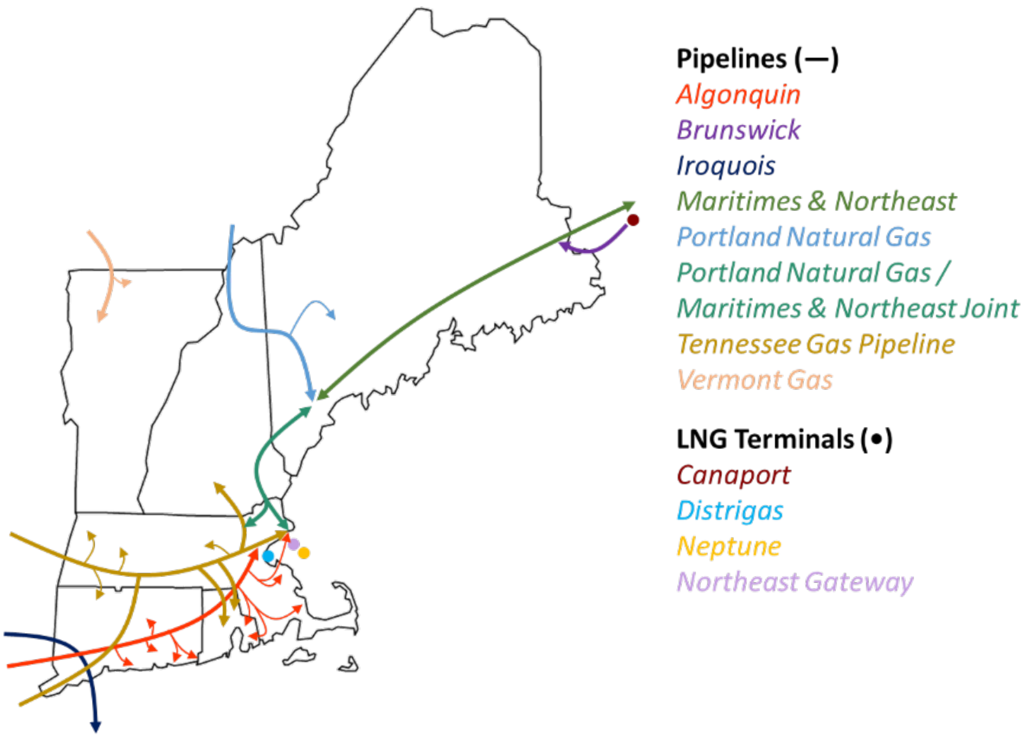
Source: ISO New England Net Energy and Peak Load by Source. (Renewables include landfill gas, biomass, other biomass gas, wind, grid-scale solar, municipal solid waste, and miscellaneous fuels. This data does not include imports or behind-the-meter resources.)

All told, New England currently consumes less than 3 Bcf/day of natural gas for all end-uses on average, although on peak winter days natural gas consumption is higher at between 5 and 5.6 Bcf/day (with most going toward heating and only 1 Bcf or less for electricity). It is likely that more gas would be consumed on those winter days (e.g., through increased utilization of the gas-fired electricity generators) if New England had additional firm pipeline capacity.

2.4. Gas Supply Infrastructure

There are currently five interstate pipelines into New England, with 2,588 miles of pipe (see Figure 10). In addition, New England has two operating LNG facilities capable of bringing natural gas into New England, with one more located just north of Maine in New Brunswick, Canada. Three of the five New England pipelines and two of the three LNG terminals bring natural gas directly into Massachusetts. Once in Massachusetts, the natural gas is delivered to 1.6 million end-use customers by 11 natural gas distribution utilities through more than 21,600 miles of distribution pipes.

Figure 10. Existing New England pipelines



Source: Synapse Energy Economics, Inc. Avoided Energy Supply Components in New England: 2018 Report.

Table 3 shows all the pipelines and LNG facilities currently serving New England including the owner, capacity, and entry points. The current gas pipeline capacity into New England is around 4.5 Bcf/day. LNG capacity into New England is designed to provide potentially 1 Bcf/day of gas when vaporized into the pipeline system (0.7 from Distrigas at Everett and 0.4 from an offshore on-loading facility called Northeast Gateway)[2] but some of that LNG can only be delivered through the existing interstate pipeline system when there is capacity available.

[2] Northeast Gateway has provided multiple cargoes, but the capacity is fairly limited and it didn't provide any cargoes during the last two winters. Neptune, another offshore unloading facility has only had a test cargo and is officially offline.

Table 3. New England major existing pipeline and LNG infrastructure

Name	Owner	Capacity	Entry Points
Existing Pipelines			
Algonquin (includes recent AIM project)	Enbridge	1.8 Bcf/day	NY, CT, MA, RI
Tennessee (includes recent CT expansion)	Kinder Morgan	1.4 Bcf/day	CT, MA, RI, NH
Maritimes & Northeast	Enbridge, Emera, & Exxon/Mobil	0.8 Bcf/day	New England from Maritimes
Portland Natural Gas Transmission (PNGTS)	TransCanada & Gaz Metro	0.2 Bcf/day	W. Canada to New Hampshire and Maine
Iroquois Gas Transmission	TransCanada, Dominion, Nat'l Grid, etc.	0.3 Bcf/day (of 1.6 Bcf/day capacity delivered to NE)	CT
LNG Facilities			
Distrigas	Exelon	0.7 Bcf/day; 3.4 Bcf storage	Everett
Neptune	Engie	0.4 Bcf/day; no storage; not operating/license deactivated	Offshore Cape Ann, north of Boston
Northeast Gateway	Excelerate Energy	0.4-0.8 Bcf/day; no storage	Offshore Cape Ann, north of Boston

Source: From Northeast Gas Association information based mainly on EIA data.

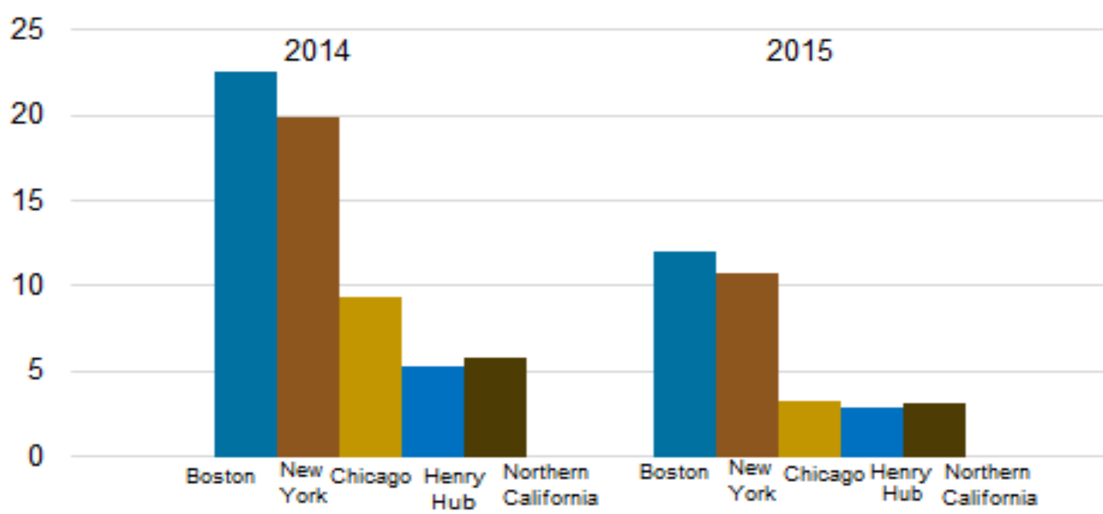
There are also LNG storage/peak-shaving facilities in five New England states with a total storage capacity of 16 Bcf. 11 Bcf of this capacity is in Massachusetts and owned by local gas distribution utilities in 18 communities. Local gas distribution companies can in theory inject approximately 1.4 Bcf/day from the 16 Bcf of total stored regional LNG directly into their distribution pipelines. This could supplement the interstate pipeline delivery capability to end-use customers (but not typically to power generators) within the limitations of their on-site storage volumes. Utility LNG storage is designed to meet only a few days of peak winter conditions. Additional LNG, on the order of magnitude of 0.1 Bcf/day, can be distributed by truck from the Distrigas LNG facility in Everett to the various storage facilities throughout New England (none of which are currently located at electric generation facilities). LNG could also be delivered by truck from outside New England. The trucking is primarily done in the spring and summer months to refill the tanks prior to the winter heating season. Trucking refills in the winter months are possible, but more limited.

2.5. Gas Basis: A New England Regional "Premium"

Because gas demand has been increasing in New England without large increases in gas delivery capability, regional prices have remained high relative to the rest of the United States. This price imbalance is particularly acute in the winter when the high-demand for natural gas for heating reduces the supply available for electricity generation.

As Figure 11 below shows, natural gas prices in Boston can be more than three to four times higher than the reference Henry Hub[3] gas price—and more expensive than other cities such as New York City and Chicago. While wintertime pipeline natural gas prices were lower in New England in 2015 than they were in 2014, due to a variety of factors including higher LNG imports into the region—pipeline delivered gas prices remained over three times higher in New England than at the Henry Hub.

Figure 11. Average wholesale natural gas pricing at key trading locations, east and west for January 1 to February 20 (dollars per million British thermal units)



Source: Natural Gas Intelligence retrieved from EIA. Note: The trading hubs represented here are Algonquin Citygate for Boston, Transco Z-6 NY for New York, Chicago Citygate for Chicago, and PG&E Citygate for Northern California. Henry Hub is the standard trading benchmark for U.S. natural gas.

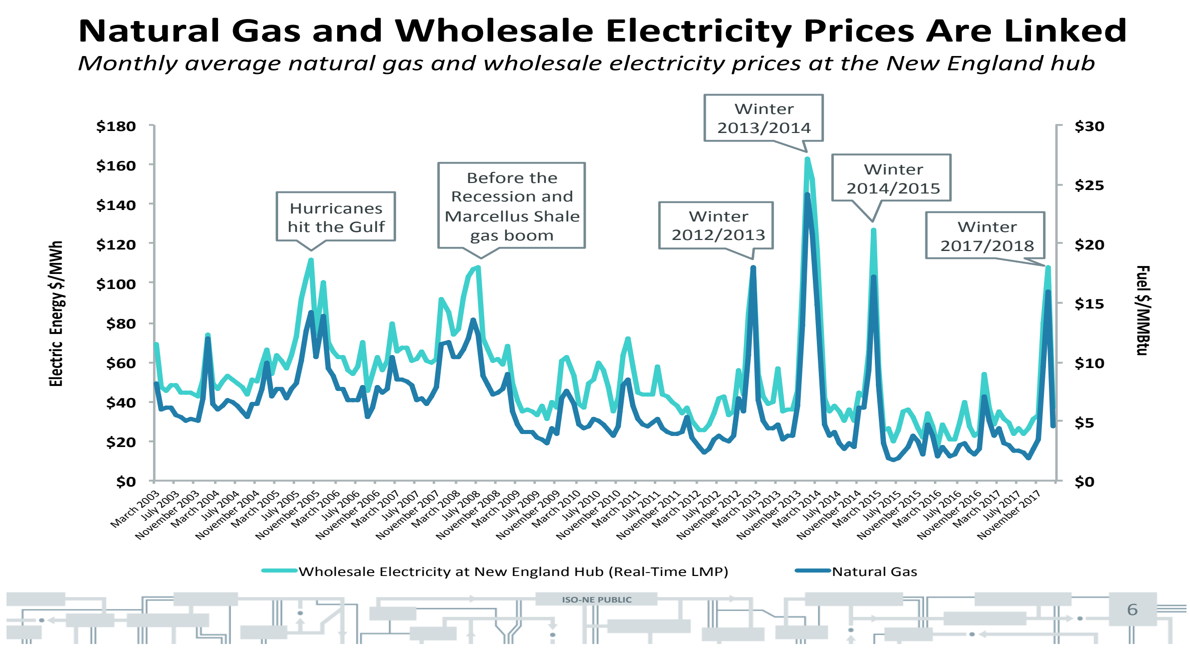
2.6. Winter Gas Effect

In the winter when gas is needed for both space heating and electricity generation in New England and throughout the Northeast and Mid-Atlantic, natural gas prices rise.

[3] Spot and future natural gas prices set at Henry Hub are generally seen to be the primary price set for the North American natural gas market. North American unregulated wellhead prices are closely correlated to those set at Henry Hub."

These increases have a direct impact on wholesale electricity prices because (a) electric generation in New England is increasingly dependent on natural gas, and (b) gas-fired generators tend to be “on the margin” in the ISO New England system—meaning they set the wholesale electricity prices that all generators receive in a given timeframe from the market. On the coldest days, when gas supplies are limited and gas prices are the highest, the marginal generation fuel is usually oil or LNG that is priced below the cost of pipeline gas. Figure 12 shows the pattern of rising gas and electricity costs in the winters, and the linkage between gas and electricity prices.

Figure 12. Natural gas and wholesale electricity prices in New England (2003–2017)



Source: ISO New England: Monthly average natural gas and wholesale electricity prices at the New England hub.

2.7. Emissions Profile of Natural Gas and Methane Leaks in Massachusetts

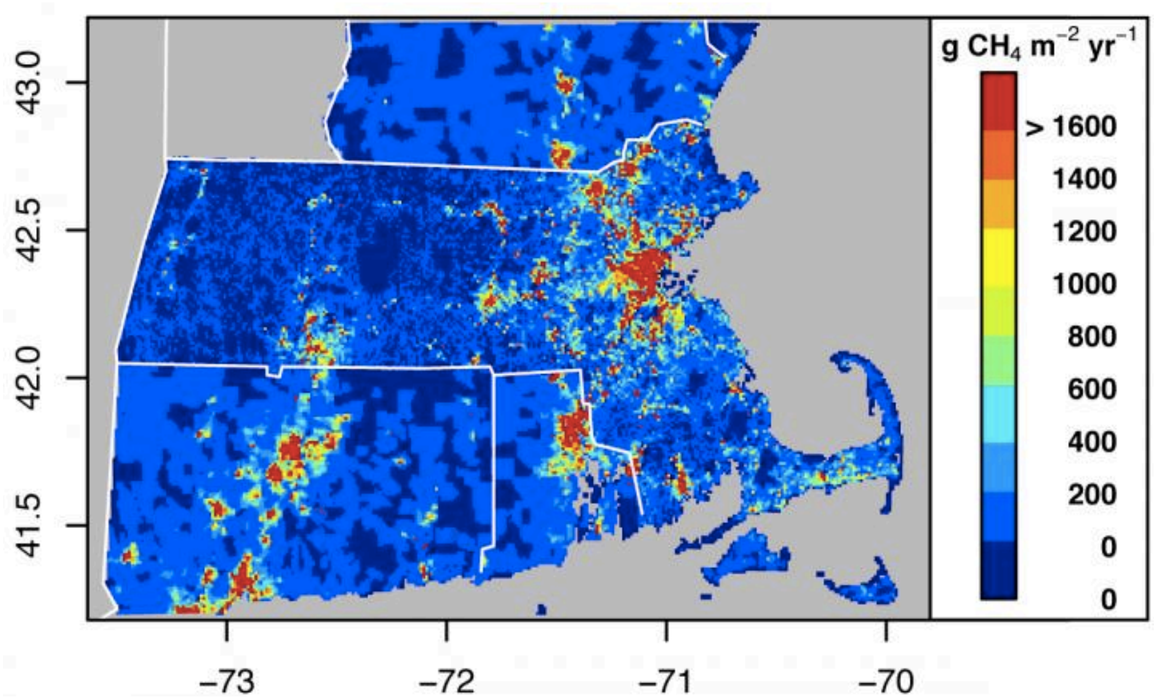
Natural gas has a lower carbon dioxide (CO_2) greenhouse gas (GHG) emissions profile than oil, propane, or coal at the point of consumption/burning. Hence, fuel switching to natural gas from coal or oil for electricity generation and from heating oil and propane for home heating had historically been viewed as a potential climate mitigation measure. However, it’s important to note that when natural gas escapes at the point of extraction or during transit from production to end users, it is generally emitted as methane rather than as CO_2. Methane emissions are much more potent than CO_2 on a pound for pound basis. To the extent that methane is released during extraction and transportation (through transmission and distribution pipelines), this reduces the relative GHG benefits of switching from coal, propane, or oil to natural gas.

Some experts estimate that when you look at the full fuel cycle (including extraction and transportation/delivery—and not just final combustion), natural gas is not much better than other fossil fuels. They note that in certain circumstances natural gas can be worse from a GHG emissions perspective. In addition to climate-related concerns about methane, there are also numerous other local environmental and health concerns (e.g., drinking water and local air pollution), and even seismic related issues surrounding the fracking process itself. These climate and potential local impacts have all been critical areas of competing studies and debate.

It's further important to note that with the advent and recent improvements of cold-climate heat pumps, switching from heating oil or propane to electricity rather than to natural gas is now viewed as the preferred environmental alternative.

A recent study by Harvard University published in the *Proceedings of the National Academy of Sciences* mapped the methane leaks from gas distribution systems in New England (see Figure 13 for methane detection throughout New England). The study estimated that 2.7 percent of gas intended for delivery to Boston leaks from the distribution system before it reaches end-use customers. This escaped gas is released into the atmosphere as methane.

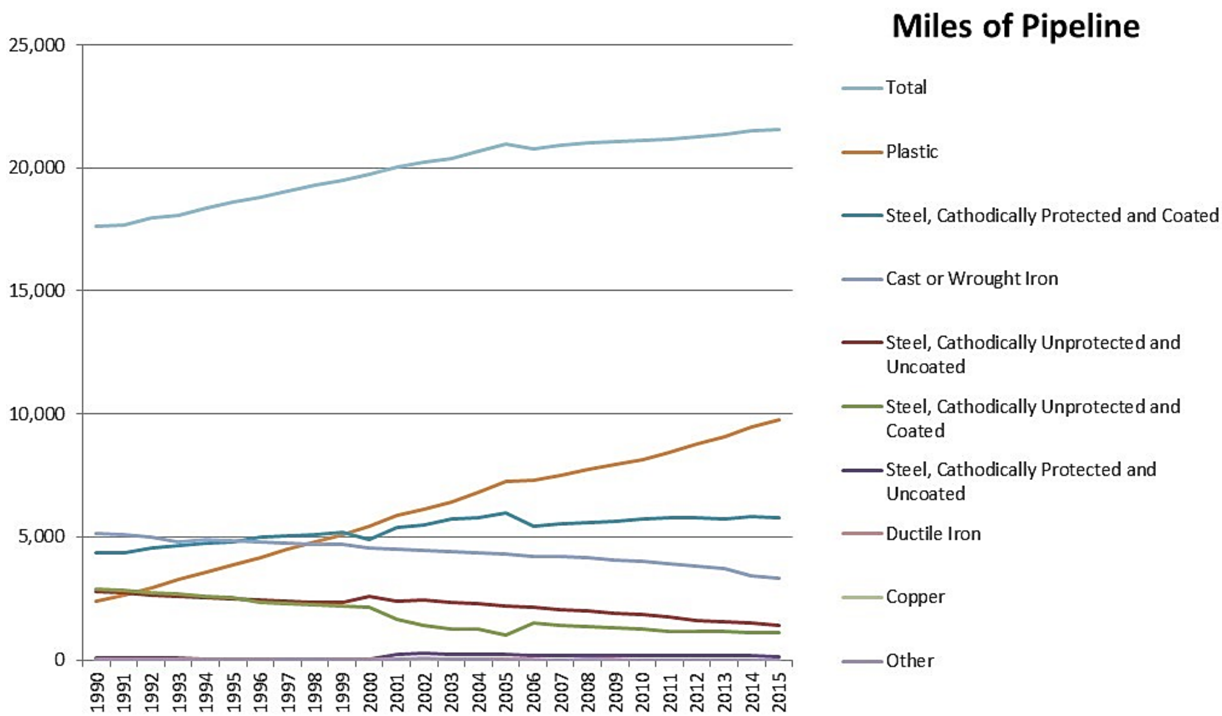
Figure 13. Methane leaks from gas distribution systems in southern New England



Source: McKain, K. et al. 2014. "Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts. Proceedings of the National Academy of Sciences.

A key factor in Boston and New England methane emission estimates is the state of the local distribution system infrastructure. Notably, Massachusetts has a considerable amount of older pipe considered “leak-prone” (i.e., cast-iron and bare steel comprise over 20 percent here compared to the national average of about 7 percent). Leaky pipes, in addition to emitting GHGs, can in certain circumstances pose a significant safety hazard (from potential explosions and fires). In June 2014, the Massachusetts Legislature unanimously enacted a bill (H. 4164) to accelerate the replacement of older utility distribution systems to enhance safety and reduce emissions. Figure 14 shows the composition of distribution pipelines over time in the Massachusetts inventory.

Figure 14. Distribution Gas Pipe by Type in Massachusetts (1990–2015)



Source: Northeast Gas Association. .

3. Major Recent Gas-Related Developments in Massachusetts and New England

Over the last three years (since the first draft of this paper came out) there have been many developments related to the future of natural gas supply and demand in New England, Massachusetts, and Boston that are worth discussing. These developments include (1) important new studies; (2) policies, legislation, and a Massachusetts Supreme Judicial Court decision related to potential support for new gas pipelines and supply; (3) pipeline project completions and cancellations; (4) renewable energy-related developments; and (5) developments related to electricity supply and generation that impact gas issues in the near and long terms.

3.1. Gas Infrastructure and Electric Grid Reliability Studies

Experts have undertaken a multitude of studies to explore New England's increasing reliance on natural gas-fired electricity generation, in light of New England's current gas infrastructure. Many explore whether additional gas infrastructure and supplies will be needed or should be constructed. All the studies have focused on electric reliability, but some also studied costs, energy prices, and climate impacts. Some of these studies concluded that additional gas infrastructure would be advisable, while others concluded that electric reliability could be maintained through other means. Most notably, starting from the most recent:

- **ISO New England's Operational Fuel Security Analysis** released in early 2018 evaluated the risks to the electricity grid for an extreme winter in 2025 assuming no additional gas pipeline capacity into New England from what exists today. The ISO model showed that in most of the 23 ISO scenarios the region would experience load-shedding, suggesting a trend towards increased fuel-security risk. It concluded that higher levels of LNG, imports, and renewables—could minimize system stress and maintain reliability. It further concluded that delivery assurances for LNG and imports, as well as transmission expansion, will be needed. https://www.iso-ne.com/staticassets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

  After the ISO's January release, the ISO modeled numerous additional scenarios requested by a group of NEPOOL participants. Modified assumptions that reflect current demand trends and existing state renewable energy requirements (including Massachusetts legislation to increase hydro imports) showed zero operational issues and no load-shedding for an extreme winter. [Note that many of the scenarios with revised assumptions are consistent with the ISO's conclusion that higher levels of LNG, imports, and renewables would be needed to ensure a reliable electric grid in the absence of additional pipeline infrastructure.] Those scenarios are available at: https://www.iso-ne.com/static-assets/documents/2018/05/a2_operational_fuel_security_presentation_march_2018_rev1.pdf.

- **Massachusetts Attorney General** commissioned a regional study to examine options for addressing electricity reliability needs through 2030. Analysis Group conducted the study, which contained an evaluation of all potentially available energy resource options. These options included natural gas (both natural gas pipelines and LNG), oil, hydro imports, energy efficiency, demand response, and renewables. The assessment covered the costs and benefits, price impacts, and

GHG emissions profile of each option. The study (which included a high-level stakeholder study advisory group facilitated by Raab Associates) was completed in November 2015, after the announcement of the Pilgrim Nuclear Plant closure prompted additional modeling. It concluded that additional pipeline capacity was not needed, and that there were less expensive and cleaner options for maintaining electricity reliability. http://www.mass.gov/ago/docs/energy-utilities/reros-study-final.pdf.http://www.mass.gov/ago/docs/energy-utilities/reros-study-final.pdf.

- **Eastern Interconnect Planning Collaborative (EIPC),** representing the entire electric grid east of the Rocky Mountains, hired Levitan Associates with U.S. DOE funding to conduct a Gas-Electric System Interface Study in 2014/15 for the Eastern Interconnect including New England. This study concluded that additional gas infrastructure and supply was needed in New England. http://www.eipconline.com/uploads/FinalDraftT2Report.pdf

- **Massachusetts Department of Energy Resources,** in 2014, hired Synapse Energy Economics to conduct a Low Gas Demand Analysis just for Massachusetts (with a stakeholder engagement process facilitated by Raab Associates). The study looked at eight scenarios including four with much more aggressive demand reduction strategies than Massachusetts currently deploys, and two scenarios with increased hydro imports from the north. In the scenarios studied, a need for additional gas pipeline capacity primarily for the power sector was indicated, ranging from 0.6 Bcf/day to 0.8 Bcf/day just for Massachusetts between 2020–2030. Interestingly, by 2030, several scenarios showed that incremental gas pipeline expansion needed in the earlier years would no longer be required in later years, based on the cumulative acquisition of non-gas resources. This analysis did not require compliance with the *Global Warming Solutions Act* and did not specifically explore potential policies designed to obviate gas pipeline expansion. http://www.raabassociates.org/Articles/doer-low-demand-report-final.pdf.

- **New England States Committee on Electricity** (NESCOE) hired Black & Veatch to conduct a study in 2012/13 to assess the sufficiency of gas infrastructure to support power generation. From the study, the states concluded that an additional pipeline provides the most substantial economic net benefits to electricity consumers of all solutions studied under the Base Case & High Demand Case. The study noted that further analysis would be required to determine whether policies that would result in a Low Demand Scenario are cost-competitive with infrastructure investments. http://www.nescoe.com/uploads/Phase_II_Report_FINAL_04-16-2013.pdf.http://www.nescoe.com/uploads/Phase_II_Report_FINAL_04-16-2013.pdf.

3.2. Paying for New Gas Infrastructure/Supplies

As shown previously, gas used in both the home heating sector and for electricity generation grew substantially up until 2011 in Massachusetts and New England (largely driven by the lowering of gas costs with the development of Appalachian Shale gas). After 2011, gas consumption leveled out in part due to constrained pipeline infrastructure and in part due to decreased demand for electricity. Historically, new gas pipeline infrastructure is only built when buyers are willing to make firm commitments for long-term purchases of gas (typically five years or more). Local gas distribution companies generally enter into firm gas contracts to serve their gas-heating customers. Rarely, if ever, do owners of gas-fired generators enter into long-term firm gas contracts. Since there is usually adequate gas available for gas generators at reasonable prices—except for the coldest winter days when virtually all pipeline capacity is dedicated to LDCs' heating demand—there's little incentive for gas generators to sign long-term contracts for firm gas.

To address this lack of incentive for gas-fired generators to enter into firm gas contracts, New England Governors and other stakeholders have been exploring options to spur development of additional gas pipeline capacity. In 2014, the Federal Energy Regulatory Commission (FERC) let it be known (informally) that it did not think it would be appropriate for wholesale electricity customers to pay for gas pipelines to serve electric generators. Subsequently, states began exploring the possibility of having retail electric ratepayers pay for gas pipeline capacity dedicated to electricity generation. The Maine legislature had already given the Maine PUC such authority, and both Rhode Island and Connecticut regulators were later granted similar authority.

However, the Massachusetts Supreme Judicial Court in August 2016 vacated a Department of Public Utilities' order on the topic. In the vacated order, the Department had determined it was authorized to review and approve ratepayer-backed, long-term contracts entered into by electric distribution companies for additional natural gas pipeline capacity in Massachusetts. In decision number SJC-12051, the court explained that, "the department's approval of ratepayer-backed, long-term contracts by electric distribution companies for gas capacity contradicts the fundamental policy embodied in the [1997 electricity] restructuring act, namely the Legislature's decision to remove electric distribution companies (EDCs) from the business of electric generation." Massachusetts, like the other states, would therefore need express legislative authority to allow for such purchases by the EDCs. Given the ongoing controversy surrounding potential new gas pipelines in the Commonwealth, it is unlikely that such authority will be readily forthcoming.

Meanwhile, ISO New England has put in place a set of "Pay for Performance" rules that will penalize generators who have firm capacity obligations but do not provide electricity when called upon (while concurrently incentivizing generators who do provide electricity when requested). But these rules are just now coming into force, and it is generally recognized that the penalties and incentives will likely not be sufficient to result in firm long-term contracts by owners of electricity generation for pipeline gas. More likely these "Pay for Performance" rules will incentivize gas generators to pursue less expensive alternatives including dual-fuel generation capability, onsite oil storage, and shorter-term LNG contracts.

3.3. The Fate of the Major Gas Pipeline Proposals

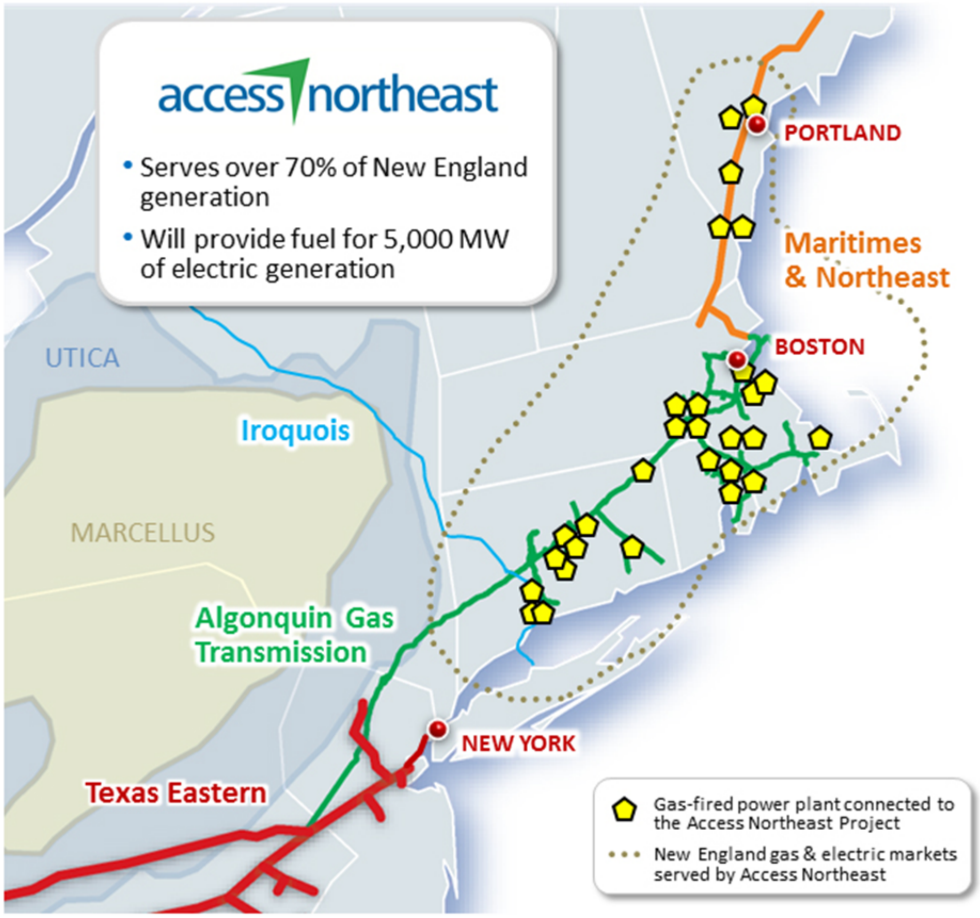
There were two large pipeline projects proposed to bring significant incremental new gas into New England—the Northeast Energy Direct Project (NED) and the Access Northeast Project (descriptions below). These projects could have brought an additional 1-3 Bcf/day of gas into New England at an estimated capital cost of $3-6 billion[4]

1. **Northeast Energy Direct (NED) Project—**This would have been a new west-to-east pipeline built by Kinder Morgan, owner of the Tennessee Gas Pipeline into New England. It would have come from New York into western Massachusetts and southwestern New Hampshire. It would have been scalable to 2.2 Bcf/day. Kinder Morgan announced commitments of approximately 0.5 Bcf/day from nine local gas distribution companies for their end-use customers—but supposedly no gas-fired electricity generators made commitments. This pipeline as originally designed would have primarily been a greenfield project (i.e., not expansion of existing pipe), and it had engendered local controversy in western Massachusetts. Kinder Morgan had proposed a substantial re-routing of the project with most of the pipe routed through existing rights of way and also into southern New Hampshire. Kinder Morgan cancelled its NED project in April 2016, citing inadequate capacity commitments.

2. **Access Northeast Project** (shown Figure 15)**—**This would have been a further expansion of the existing Algonquin and Maritimes pipeline system (that runs north/south in New England) and was being proposed by Spectra (now Enbridge) in partnership with Eversource and National Grid. Their proposal was to provide up to 1 Bcf/day that would have been primarily dedicated to providing gas for power generators. The existing pipeline is in close proximity to approximately 70 percent of New England's existing gas-fired generators (see map below), and Spectra estimates this gas could support 5,000 MW of power generation. This was put on "indefinite-hold" by Enbridge in June of 2017, again due to inadequate capacity commitments.

[4] These capital costs do not include annual operation and maintenance costs (which would likely be billions of additional dollars over the life of the pipelines). It also does not include the actual gas commodity costs. However, it is also unlikely that both projects would have been built due to significant overlap of the intended markets.

Figure 15. Proposed Access Northeast project route



Source: Access Northeast.

In addition to local land-use concerns (especially with the NED project, which was more of a greenfield project than Access Northeast), environmental groups,consumer advocates, and others were very concerned about the effect that increased natural gas reliance would have on the region's ability to comply with its GHG reduction laws. They argued that increased gas supplies that do not reflect GHG costs will undermine the development of zero-carbon resources(energy efficiency and renewables) while locking the region into additional long-term fossil fuel commitments. Instead, these stakeholder groups advocate for ramping up distributed energy resources and utility-scale renewables. They also advocate for using LNG and electricity storage to deal with short-term peak problems rather than locking the region into additional gas pipeline infrastructure and long-term gas contracts for the sake of a few extreme winter days in some years. Expanded gas supply may not be needed for the long term and could lead to substantial stranded costs. As mentioned in the previous section, numerous studies have evaluated the costs and benefits of pipeline expansion compared to other alternatives. [Note: To understand more about how the pipeline siting process works, see Appendix A from the original primer.]

In the end, without sufficient incentives for gas generators to sign up for long-term, firm gas delivery and with the Massachusetts Supreme Court prohibiting EDCs from assigning the costs and risks for such contracts to their ratepayers—there was insufficient firm demand to justify the pipeline investments. The NED project was canceled in 2016 and Access Northeast was put on indefinite hold in 2017.

Although there has been much media attention in New England surrounding these two large potential gas pipelines (each over 1 Bcf), nearly 0.5 Bcf of pipeline capacity into New England has been added over the last year-and-a-half through a series of smaller expansion projects (Table 4). The gas from these projects is primarily planned for end-use customers rather than electricity generators. These projects include:

1. **AIM Project**—This is an expansion of the existing Algonquin Pipeline owned by Spectra to deliver an additional 0.3 Bcf/day to six utilities/cities for end-use customers. It includes some modifications/additions in Boston, and it received its FERC certification in March 3, 2015.

2. **Connecticut Expansion Project**—This is an expansion of the existing Tennessee Pipeline owned by Kinder Morgan to deliver an additional 0.07 Bcf/day to two Connecticut Utilities.

Table 4. Smaller gas pipeline expansion projects in New England

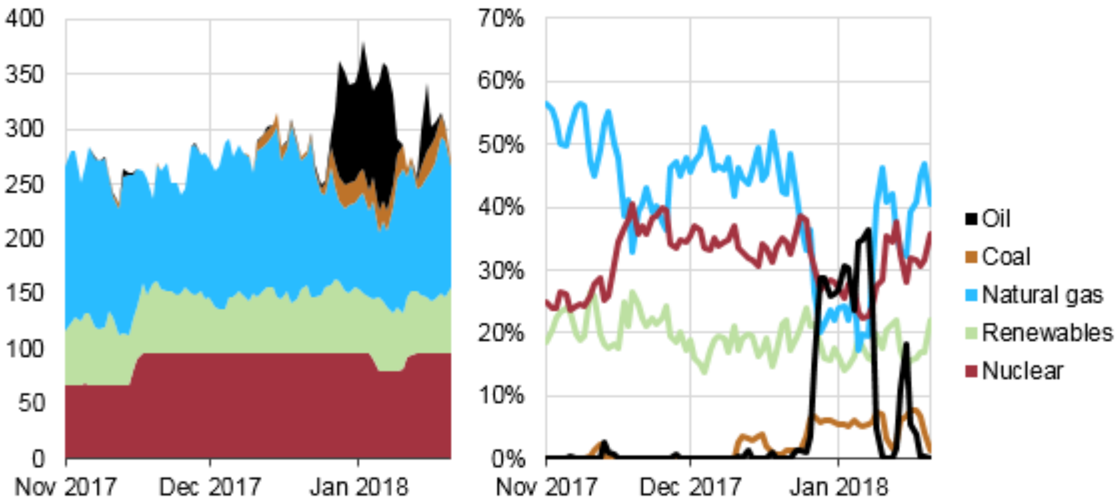
Developer	Project name	Project capacity
Enbridge	AIM Project	.3 Bcf/D
Enbridge	Atlantic Bridge Project	.04 Bcf/D
PNGTS	C2C Project	.03 Bcf/D
Tennessee	CT Expansion	.07 Bcf/D
	Total	.45 Bcf/D

Source: Northeast Gas Association. "Projects entering service in New England over last year," slide 21.

3.4. Grid Reliability and Fuel Security—Winter of 2017–18

This past winter proved to be a major stress test for the region's electricity system, with 12 consecutive days of bitter cold and several powerful Nor'easters. During the 12-day period from late December to early January, gas space heating demand rose sharply. This limited the gas available for electricity generation. To compound matters, the Pilgrim nuclear power plant (680 MW) went off-line due to the loss of a transmission line servicing the plant during one of the storms. As shown in Figure 16, gas-fired generation dropped steeply during this period. In its place, the region relied on oil-fired generation, coal-fired generation, and LNG.

Figure 16. ISO New England generation mix during 2017–18 extended cold snap

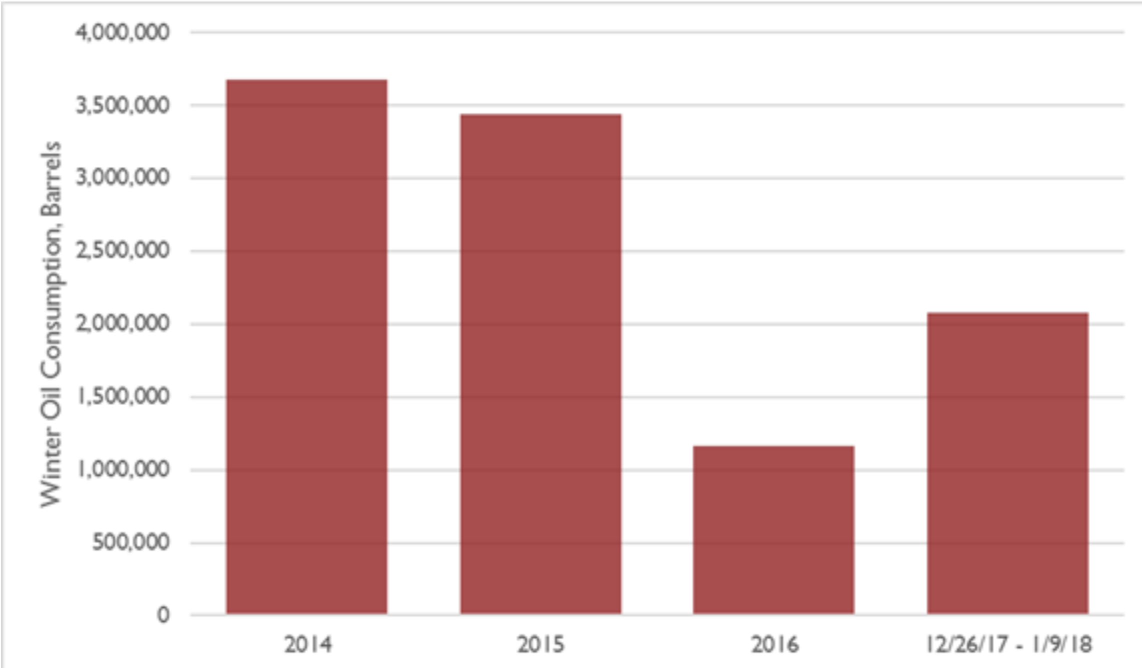


Source: ISO New England, shown in gigawatt-hours.

As shown in Figure 16, oil generators were in merit during the cold snap in January 2018. This implies that electricity prices rose during this period. Moreover, as shown in Figure 17, electricity generators burned 2 million barrels of oil during those two weeks—more than twice what generators used throughout the winter of 2016 but less oil than was used in 2014 or 2015 (about 3.5 million gallons each year).

There were no forced black-outs during this period due in large part to the ISO's Winter Reliability incentive program. Due to sunset this year, the program calls for electricity generators to store oil inventories on-site for use when the system is strained. During the Winter 2017–2018 cold snap, oil inventories dwindled from 68 percent full on 12/1/17 to 19 percent on 1/9/18, with no ready way to resupply. Several plants only had a few days of fuel remaining, forcing ISO New England to require them to hold back/curtail generation

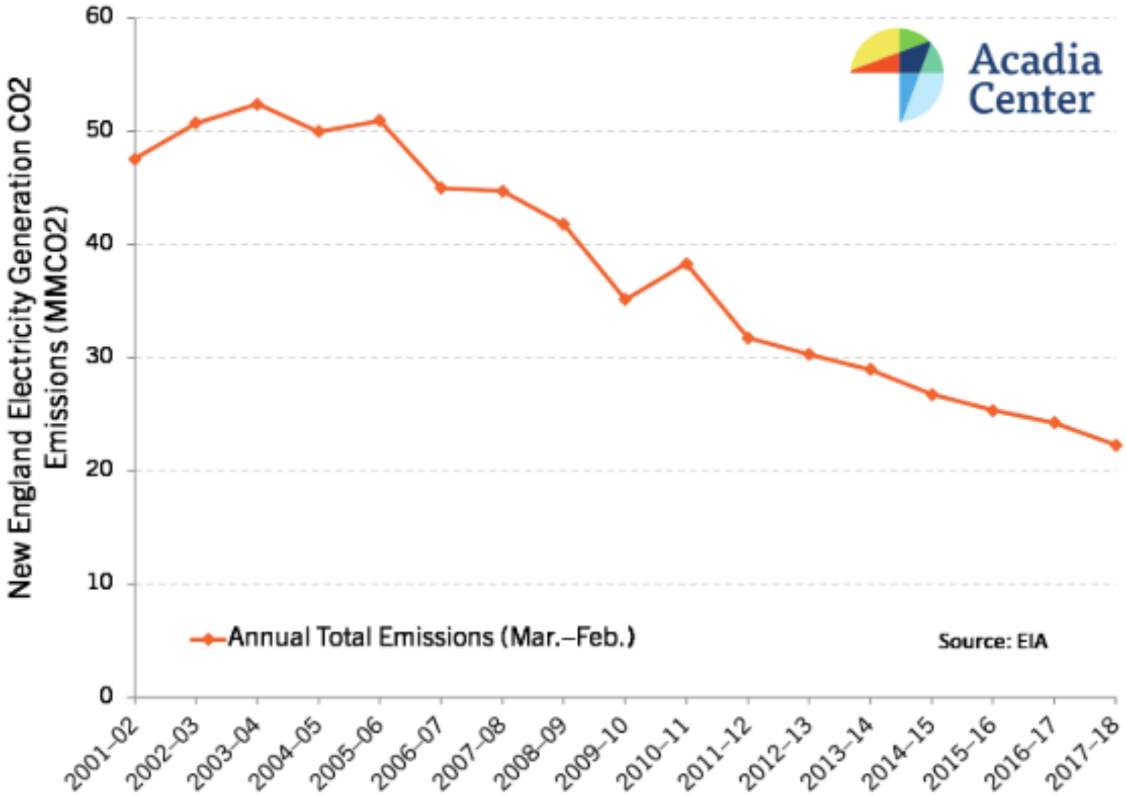
Figure 17. Oil burned for electricity generation during extended cold snap



Source: Synapse Energy Economics (from EIA Data).

Despite the increased use of oil on cold winter days over the past four winters, regional greenhouse gas emissions from electricity generation have continued their steady annual decline as shown in Figure 18.

Figure 18. Annual GHG Emissions (Mar. to Feb.) from electricity generation in New England.

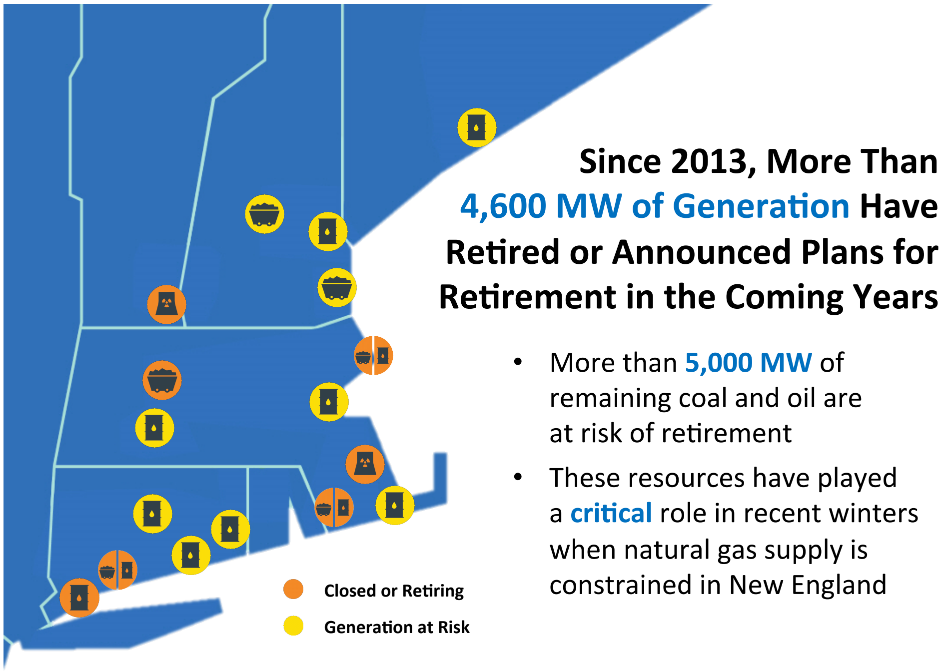


Source: Acadia Center. 2018. "Clearing the Air: Long-Term Trends and Context for New England's Electricity Grid." Available at: https://acadiacenter.org/clearing-the-air-long-term-trends-and-context-for-new-englands-electricity-grid/.

3.5. Electric Generation Retirements

Over 4,300 MW of existing electricity generators in New England have retired or announced their plans to retire since 2014. ISO New England recently estimated that another 5,000 MW of additional oil and coal facilities are at risk of retirement. These actual and potential retirements of mainly oil and coal plants (shown in Figure 19) are driven by aging facilities with poor fuel-conversion factors, lower-costs associated with gas-fired generation, and increasing amounts of renewable energy resources. ISO New England will have to continue its role of carefully managing retirements to avoid having retirements further exacerbate winter electricity price and reliability challenges. Also, gas-fired generation and renewables are currently the most obvious available options to replace energy from the retiring generators, but as discussed previously any new gas-fired generators (if needed) would be developing facilities without any guarantees of additional gas supplies being delivered into the region.

Figure 19. Retiring and at-risk New England generation



Source: ISO New England.

Against this back-drop, Exelon's announcement in late March that it planned to retire its 2,000 MW of gas-fired generation at Mystic Station by Winter 2022/23 came as a surprise to many. ISO New England, concerned about the impact that closing Mystic could have on electricity reliability in New England, filed a request at FERC for authority to retain 1,600 MW of the 2,000 for fuel security reasons through Winter 2023/24. Note that ISO's 5,000 MW of at-risk generators does not include these 2,000 MW at Mystic, nor does it include the over 2,000 MW of nuclear at Millstone. Millstone owner Dominion has asked the Connecticut Legislature for additional compensation (implying that if could shutter the power plants without it). All told, these planned, announced, and potential retirements account for more than one-third of the current installed generation in New England.

3.6. Renewable Energy Trends

All the New England states, as part of their commitments to clean energy and in pursuit of their GHG reduction requirements, continue to aggressively pursue the development of renewable energy resources through renewable portfolio standards (RPS), net metering (mainly for solar), and most recently large-scale competitive clean energy procurement processes.

As Table 5 shows, all of the states have RPS requirements in place requiring that an increasing percentage of electricity be supplied from renewable energy resources (primarily from new wind and solar resources —but some states also have tiers for existing hydro and biomass). Initially, these standards succeeded in bringing forward thousands of megawatts of mainly onshore wind. Subsequently, with the introduction of net metering, RPS carve-outs for solar, and falling solar prices, we have seen the development of thousands of megawatts of solar in the region.

Table 5. Summary of RPS targets for new resource categories, 2020–2030

	2020	2025	2030
CT-I	20%	30%	40%
ME-I	10%	NA	NA
MA-I	15%	20%	25%
MA-CES	5%	10%	15%
MA-APS	5%	6%	8%
NH-I	11%	15%	15%
NH-1 Thermal	2%	2%	2%
NH-II	1%	1%	1%
RI-New	14%	22%	29%
VT-II	3%	6%	9%
VT-III	4%	7%	11%

Source: Synapse Energy Economics, Inc. Avoided Energy Supply Components in New England: 2018 Report. MA-II RE targets subject to annual adjustment by MA DOER. Connecticut Class I supply can be counted toward compliance with CT-II requirements. Vermont Tier II supply can be counted toward compliance with VT-I requirements.

Because both wind and solar are intermittent resources (i.e., they only produce electricity when the wind blows or the sun shines), back-up power is often needed to "firm up" that generation. This back-stopping could be done by quick-start oil and gas-fired generators, by energy storage (such as batteries), or even by hydro. But each of these has its own unique set of challenges in New England presently. We've already discussed at length throughout this report the challenges of increasing reliance on gas-fired generation in a pipeline-constrained region. For hydro to firm up renewables, we would likely need to build additional transmission from Canada (discussed further below) and the hydro would need to be available at all times. Storage is promising but still relatively expensive in the near term.

Massachusetts and other states have recently begun to pursue renewable resources through state large-scale clean energy procurements (See Table 6). The first RFP in 2016 was jointly conducted by Massachusetts, Connecticut, and Rhode Island. It awarded 460 MW of mainly in-region solar and wind projects. In 2016, the Massachusetts Legislature separately passed the Energy Diversity Act that included authorization for two large-scale renewable procurements. The first procurement required EDCs to conduct an RFP for 9.45 TWh of clean energy. This translates to approximately 1,200 MW of hydro over new transmission lines. (While wind and solar were also eligible, it was generally understood that this RFP would be filled by lower cost hydro from Canada.) This RFP was originally awarded to the Northern Pass project (in January 2018) that would have brought hydro from Hydro-Quebec over new transmission lines developed and owned by Eversource through New Hampshire. But the New Hampshire Siting Council, shortly thereafter, rejected the project (claiming the benefits to New Hampshire did not outweigh the costs). Massachusetts then shifted the award to the New England Clean Energy Connect Project to bring the same hydro-power from Hydro-Quebec but through Maine over transmission lines developed and owned by Avangrid. One important feature of the hydro from Hydro-Quebec in both these bids is that it would be firm power available to Massachusetts at all times—even during winter peaks when gas-fired generation is constrained—thus significantly enhancing winter reliability.

Table 6. New England state clean energy procurements

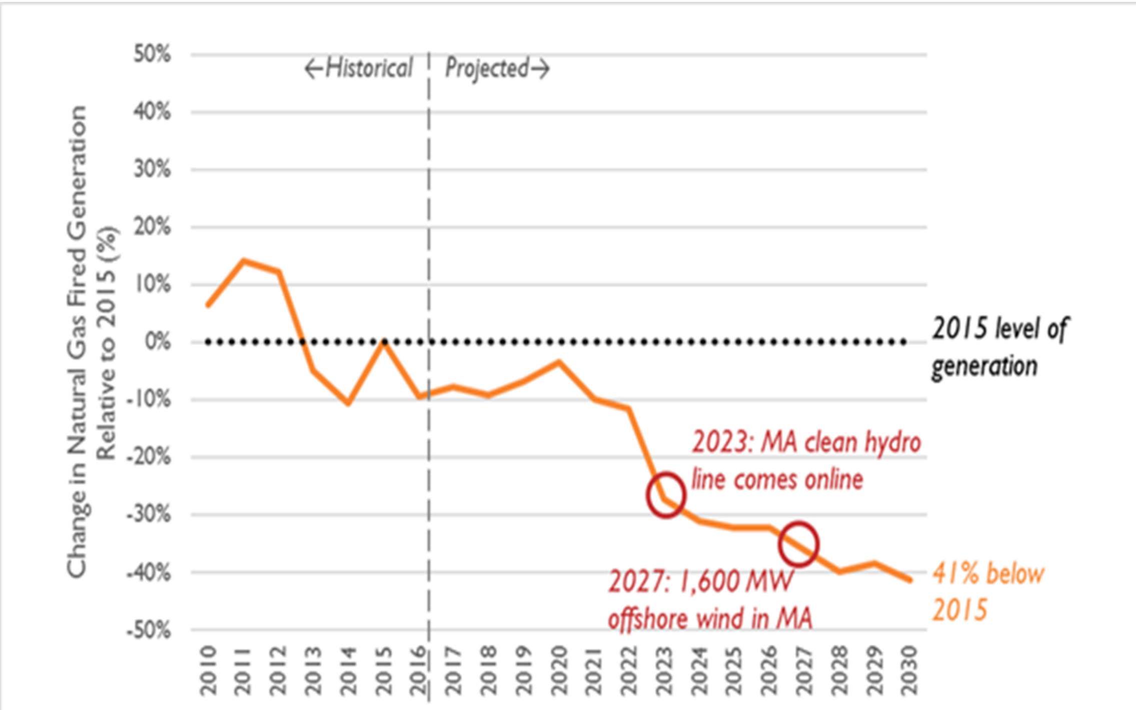
States	Recent State Resource Procurement Initiatives	Expected Resources	Target MW
MA, CT, RI	2016 Multi-State Clean Energy RFP	Solar, wind	460
MA	2016 Energy Diversity Act	Hydro imports, and other clean energy resources	Approx. 1,200
MA	2016 Energy Diversity Act	Offshore Wind	1,600

The second Massachusetts procurement process is for offshore wind and requires that 1,600 MW of offshore wind be procured by Massachusetts distribution companies by 2027. The first offshore wind RFP required a bid of at least 400 MW (with allowable alternate bids ranging from 200–800 MW). The three Bureau of Ocean Energy Management leaseholders (Deepwater Wind, Orsted, and Vineyard Wind—along with their partners) submitted bids of varying sizes. Interestingly, all three included a storage component to their bids. Massachusetts announced on May 23rd that it had selected Vineyard Wind's 800 MW proposal. Concurrently (and somewhat unexpectedly) Rhode Island announced that it planned to contract with Deepwater Wind for 400 MW.

The aggressive development of renewable energy resources in New England affects gas-fired generators in at least two significant ways. First, as mentioned previously, because solar and wind are intermittent resources, they will always need something in place to back them up and be available when they are not (and demand is not covered). Currently, oil- and gas-fired peaking generators are the most readily available and probably most cost-effective source for such back-up services. Second, to the extent that thousands of MW of renewables are participating in wholesale energy markets, they tend to lower wholesale energy prices. This makes it less economical for traditional generators, including gas-fired generators, to operate. The situation is not unlike the current impact of low-cost gas lowering energy market prices and causing economic distress for coal, oil, and nuclear generators.

A recent study by Synapse Energy Economics shows the net effect of these renewable RFPs and other factors on gas-fired generation in New England—projecting a potential decline of 41 percent between 2015 and 2030.

Figure 20. Estimated change in natural gas-fired electric generation, relative to 2015



Source: Adapted from Knight, P. et al. 2017. New England's Shrinking Need for Natural Gas. February 7 2017. Available at: http://www.synapse-energy.com/sites/default/files/New-Englands-Shrinking-Need-for-Natural-Gas-16-109.pdf. Figure ES-1.

3.7. Gas/Electricity Demand—Longer Term Trends (Including Electrification)

Due largely to extensive and aggressive ratepayer-funded energy efficiency programs in New England[5] and improved state building codes and federal appliance efficiency standards and more recently the ramp up of photovoltaic installations, electricity peak demand has been relatively flat while electricity consumption has been declining for some time in New England (see Figure 21).

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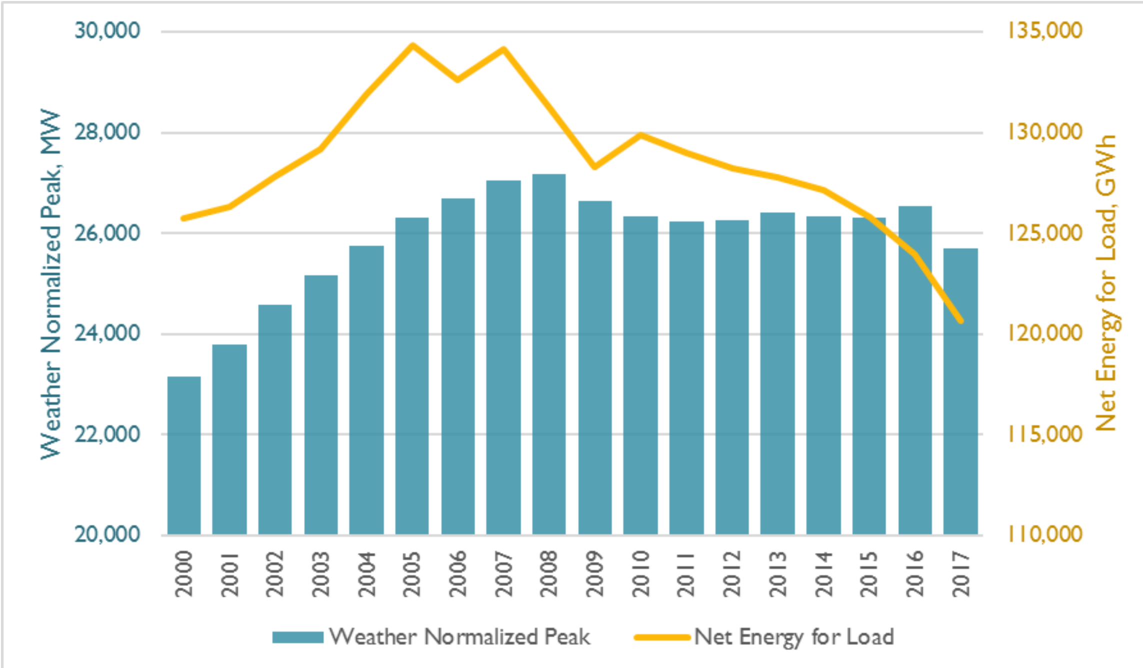
[5] Massachusetts has been the #1 ranked state in the nation for the past half-decade by ACEEE for its electricity and gas energy efficiency programs and policies (Boston has been the #1 ranked city since ACCEEE started ranking cities); and in the most recent state ranking—four New England states were in the top 10.

Figure 21. New England historical annual energy and peak loads



Source: Synapse Energy Economics from ISO-NE CELT reports through

However, as we start to explore pathways to meeting New England state GHG reduction commitments of 80 percent reductions by 2050—the most common themes emerging from numerous national and more regional studies—all seem to share three essential ingredients with regards to energy.

- Continue to improve the efficient use of energy in all sectors;
- Increase the renewable content of electricity and other fuels; and
- Electrify the heating and transportation sectors

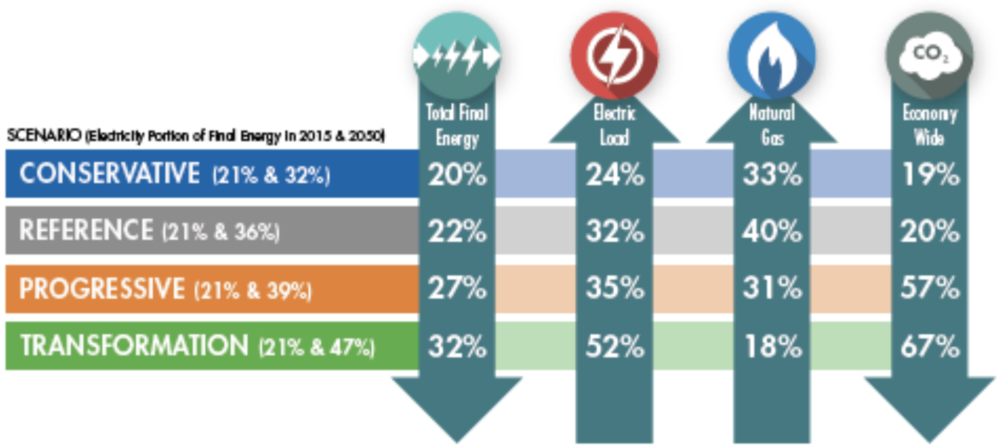
If New England is to electrify the heating and transportation sectors to the extent needed to meet its climate goals (and because electrification is generally shown to be more cost-effective than the alternatives), how much more electricity will be needed? And most germane to this report on gas in New England, how much of that electricity will need to be gas-fired and what's the net impact on overall gas demand?

Regarding the latter question, electrifying the heating sector will reduce natural gas use in that sector (to the extent that electrification occurs in gas-heated buildings and not just oil and propane). However, this could be partially off-set by increased gas use in the electricity sector. In the transportation sector, where vehicles are fueled almost exclusively by gasoline and diesel and not natural gas, electrification will not result in reductions in overall natural gas in and of itself. In fact, to the extent that gas-fired generation is still a significant part of the generation fleet, natural gas consumption could increase due to transportation electrification.

Numerous studies are underway to assess the impact of electrification on energy use across sectors and on GHG emissions. The two recent reports reviewed here show different results regarding natural gas. One is a national study by the electric utility industry and the other is a northeast-focused study done by researchers who were co-authors in the major national deep decarbonization study conducted for the Obama Administration.

The Electric Power Research Institute's (EPRI) ***U.S. Strategic Electrification Assessment*** (April 2018) looked at the impact of electrification on a variety of factors. In its most aggressive scenario entitled "Transformative Electrification" EPRI found that CO_2 could be reduced by 67 percent nationally with a 32 percent overall energy reduction; but the scenario showed a 52 percent increase in electricity use and corresponding 18 percent increase in natural gas use (Figure 22). The increased gas consumption is due to substantial increases in gas-fired electricity generation that more than off-set the decreases in natural gas use for heating in the building sector from electrification. It is noteworthy that the EPRI study's assumptions for its Transformative Electrification assumes a $50/ton price on carbon is put in place, and that much of the carbon from increased use of gas-fired electricity generation would be mitigated by carbon capture and sequestration (something the Northeast is not particularly well suited for from a geologic perspective).

Figure 22. EPRI's strategic electrification scenario results



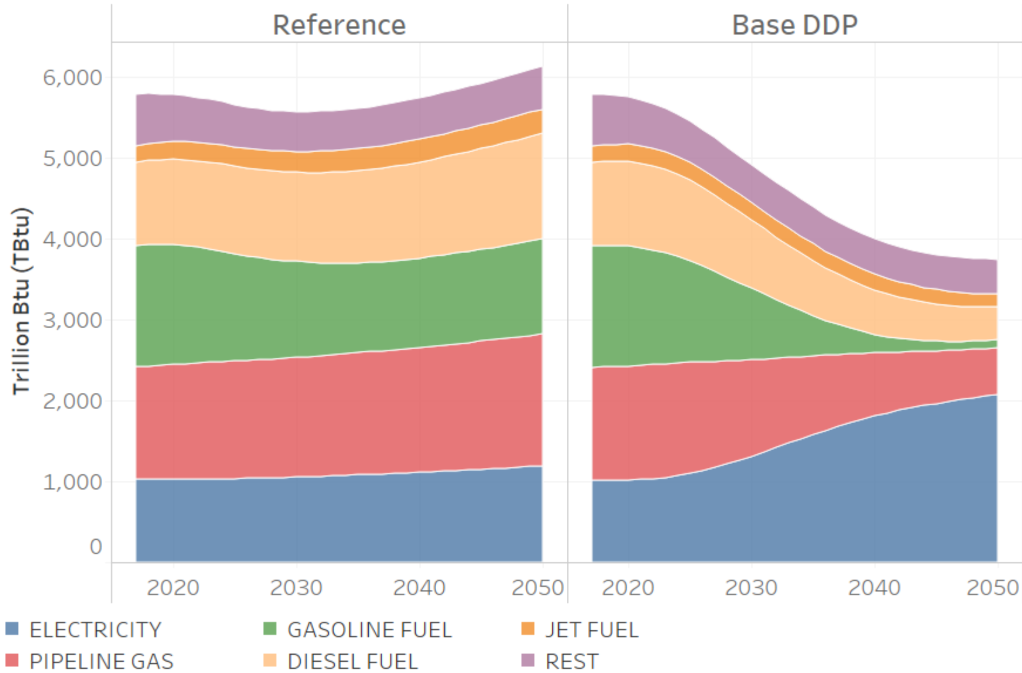
Source: Electric Power Research Institute. 2018. U.S. Strategic Electrification Assessment.

A 2018 study by Evolved Energy Research focused just on the Northeast and was entitled ***Deep Decarbonization in the Northeastern U.S. & Expanded Coordination w/Quebec Study.*** This study came up with very different results than EPRI with respect to gas demand in 2050. Conducted by several of the authors for the big U.S. study on Deep Decarbonization for the Obama Administration, the study found that the Northeast could meet its 80 percent GHG reduction requirements by 2050 aided by aggressive electrification while actually decreasing overall natural gas consumption.

In the Northeastern Deep Decarbonization study, as shown in Figure 23, deep decarbonization in a Base DDP case (which meets the Northeast 80 percent GHG reduction by 2050 requirements) would result in a substantial decrease in end-use gas consumption (i.e., mainly for heating in buildings). However, it would increase electricity use due to electrification of heating and transportation. Specifically, the authors show a doubling in electricity use overall from today, and an approximately 60 percent reduction in direct use of natural gas primarily in building sector.

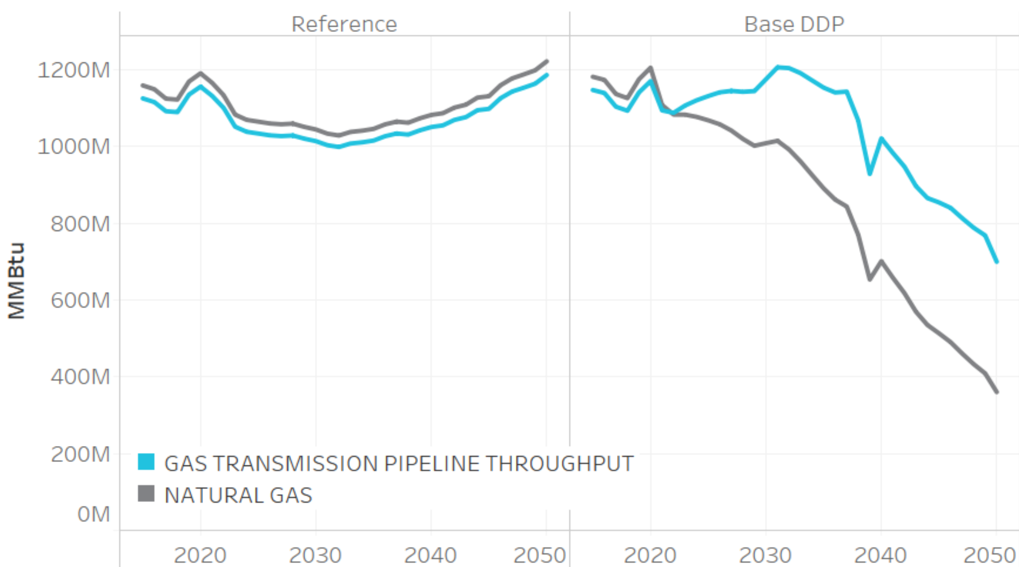
It is important to note that any increase in gas use from more gas-fired electricity generation due to electrification is not readily apparent in Figure 23 (i.e., any gas used for electricity generation is within the blue "Electricity" area in the graphic not in the red "Pipeline Gas" area). To assess the overall net impact on natural gas demand for its Base DDP just for New England (not including New York), Evolved Energy Research provided the chart and underlying data below in Figure 24. This figure shows that natural gas use would stay relatively flat through 2030 and sharply diminish thereafter through 2050. The diminishing gas demand would apply even with intensive electrification of transportation and buildings because of continued increases in efficiency in all sectors and the addition of renewables. In the Base DDP scenario, the throughput in gas pipelines would decrease by 39 percent by 2050 and the total amount of natural gas through the New England pipelines would decrease by 69 percent (with the difference between the overall throughput and natural gas drops—approximately 30 percent--comprised of biogas injected into the pipelines).

Figure 23. Northeast final energy demand by sector



Source: Evolved Energy Research et al (April 2018) Deep Decarbonization in the Northeastern Region and Expanded Coordination with HQ, page 35

Figure 24. New England natural gas consumption under deep decarbonization scenario



Source: Evolved Energy Research et al (April 2018) provided to Raab Associates for this report--from Deep Decarbonization in the Northeastern Region and Expanded Coordination with HQ analysis but not included in that Report.

4. Concluding Summary

Gas consumption in New England grew until recently due to increases in gas-fired electricity generation capacity and a substantial amount of conversions from oil and propane to gas space heating. Over the last few years, gas demand has flattened because of energy efficiency improvements, constrained pipeline infrastructure, and the relatively high cost of imported LNG.

Many stakeholders have been advocating for increased gas supply into New England to reduce gas and electricity costs and to enhance electric reliability. Many others are concerned that increasing gas dependency in New England will hinder the achievement of the region's GHG reduction requirements (approximately 80 percent by 2050), and leave customers paying for stranded costs.

Various studies have analyzed the costs and benefits of additional pipeline gas and a range of alternatives without reaching a consensus. Recent attempts to build large new pipeline infrastructure have failed due in large part to a lack of funding (through firm gas contracts). Smaller enhancements of existing pipelines have been more successful, and the region can also make use of substantial underutilized LNG infrastructure.

Recent events and trends will continue to keep natural gas in the region's cross-hairs as an important yet polarizing issue. This past winter's intensive cold snap and on-going electric generation retirement announcements continue to have many worried about the reliability of the electric grid. The pursuit of hydro from Canada, as evidenced by the recent Massachusetts RFP, can reduce some of the reliability concerns to the extent that the hydro can be utilized as a firm resource. Meanwhile, the aggressive pursuit by states of energy efficiency, solar, and wind (now including potentially plentiful quantities of off-shore wind) can displace fossil fuel and other existing resources. But because of their intermittent nature, solar and wind resources, will still need back-stopping resources such as existing quick-start gas or oil-fired generators or energy storage. Finally, electrification of the transportation and heating sectors—increasingly understood as an essential strategy to help the region meet its GHG reduction requirements—should reduce the need for gas in the space heating sector and could reduce or increase natural gas use in the electricity sector depending on a range of factors.

Appendix A: Gas Pipeline Approval Process

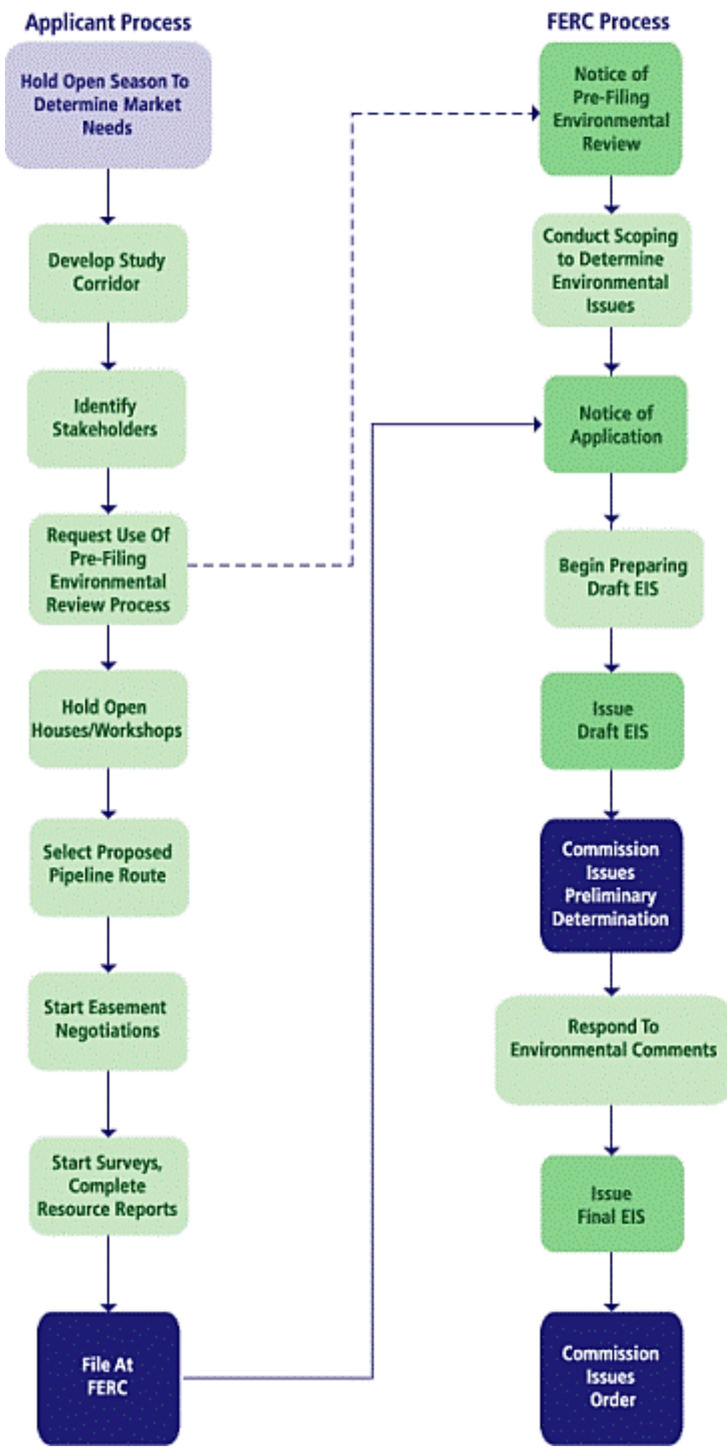
In sharp contrast to the electric transmission review and approval process where the states play a large role, for interstate gas pipelines the primary jurisdiction is with the Federal Energy Regulatory Commission (FERC). In fact, for interstate gas pipelines FERC has preemptive siting authority over the states. It can allow developers onto private property to conduct survey work and even exercise eminent domain if need be. FERC also approves the firm gas rates (recourse rates) for the pipelines. However, distribution-level pipelines that deliver gas to end-use customers (and don't cross state lines) are only subject to that state's jurisdiction for siting, health and safety, and cost recovery issues.

FERC's gas pipeline certification process, shown below in Figure 25, includes a "pre-filing environmental review process" that is required for liquefied natural gas (LNG) facilities and strongly encouraged for natural gas pipelines. (According to FERC, this almost always is used for gas pipelines as well.) The purpose of the pre-filing process is to facilitate maximum participation from all interested entities and individuals and to assist an applicant in compiling the information needed to file a complete application. FERC's goal is to allow the Commission to process the ultimate application expeditiously (i.e., within one year after the application is formally filed following the pre-filing process). FERC expects the pre-application process to take at least a year for "extensive" projects and somewhat less for facilities built mainly in existing rights-of-way.

Applicants are required to reach out and seek input from stakeholders. FERC defines these as "a Federal, State, or multistate, Tribal, or local agency, any affected non-governmental organization, or other interested person (including citizens along the likely pipeline path)." The applicant must provide stakeholders with information about the proposed project as well as a reasonable opportunity to present their views and recommendations with respect to the need for and impact of a facility covered by the permit application. This has typically been handled in the gas pipeline pre-filing processes by holding a series of "open houses" at strategic geographic locations along the proposed route. There are no firm rules explaining how these open houses ought to be structured, but the goal is to foster two-way communication between the applicant and all relevant stakeholders. In the past, they involved informal workshops, formal transcribed testimonials or simply information booths offering descriptions of various aspects of the proposed projects. Applicants are also expected to coordinate with any separate permitting and environmental reviews by other federal, state, or local agencies.

At the beginning of the pre-filing process, each applicant must file a “Participation Plan” and develop a project specific website.

Figure 25. Gas pipeline applicant and FERC review and approval process



Source: FERC

This prefiling phase is also typically the time during which state siting councils/boards will initially weigh in on a project. For instance, in Massachusetts, the Energy Facility Siting Board will conduct its own public hearings on a pipeline project and will provide comments to FERC to try and improve the project design and reduce environmental impacts. The state siting board can also require landowners to provide access to a developer for survey purposes if requested by a developer and after holding an investigation.

In many ways proposals to build or enhance interstate gas pipelines are analogous to building transmission to meet economic (rather than reliability) needs. As such pipeline developers, prior to officially filing their pipeline applications at FERC also hold “open seasons.” The aim is to first identify potential purchasers/customers of their proposed new/ incremental gas supplies (referred to as shippers), and later to secure firm long-term contracts with gas shippers. This showing of interest (ultimately through firm gas contracts), is used to demonstrate “economic need” at FERC. Generally, it is rare for pipeline developers to formally file their application without 80–100 percent of their expected gas volume already committed in firm contracts with customers (shippers).

Once firm contracts are negotiated between the developer and local distribution companies, they would be submitted first to the state regulator for review and approval. These are called “precedent agreements” (as they precede the actual FERC approval of the pipeline). Typically, since the final pipeline size and gas pricing are not yet known at this pre-filing stage, the contracts are generally structured as not-to-exceed amounts with a most-favored nation clause that would entitle the buyer to lower prices if warranted by the ultimate size, design, and pricing. Typically, these contracts are approved by state PUCs in under a year. With these anchor tenant contracts in hand (again typically for a majority of the gas to be supplied by the pipeline), and the pre-filing public engagement process complete, the developer can formally file at FERC.

When an applicant files a formal notice following the pre-filing process, it must include a summary of the points made by stakeholders during the pre-filing process and indicate how, if at all, it has addressed them. It is important to note, however, that while the gas pipeline pre-filing siting processes is structured to both inform stakeholders about the proposed project and to garner their input, it is not designed as formal consensus-seeking efforts. This does not preclude an applicant from modifying its initial plan in response to concerns raised during the pre-filing process. Nor are applicants forbidden from commencing negotiations on their own with local landowners and communities about land easements and any other matters, at any time they prefer. Once a formal application has been filed, FERC begins its legally-mandated process and stakeholders that want to continue to be involved must formally intervene (by filing a motion) in the case.

Once filed at FERC (including any and all precedent agreements with buyers), FERC orchestrates a NEPA environmental review of the project engaging other relevant federal agencies. FERC’s review typically takes up to a year. The state energy facility siting councils typically intervene at FERC to represent the state in their proceedings. FERC also looks at the need for the project, but if there are buyers lined up, the project is generally assumed to be needed. Once the pipeline review is deemed complete including the Environmental Impact Statement, FERC approves the project (often with conditions), issues a certificate that allows the developer to begin construction, and approves the “recourse rates” for firm service for off-take along the pipe. At this point, interveners in the case have 30 days to request a rehearing (as recently happened in the AIM pipeline case in Boston), and FERC’s decisions are appealable to the court.

Because these are essentially “economic” projects, with pipeline companies only seeking approval once they have their customers largely lined up—FERC would not normally be making a determination regarding whether a region like New England “needs” an additional 1, 2, or more Bcf/day. So if both Kinder Morgan with its NED project, and Spectra/Eversource/National Grid with its Access Northeast project (see detailed descriptions of these pipeline proposals above), each come to FERC with 1 Bcf pipeline project proposals, and the gas is being sold to different customers/shippers through long-term contracts (whether it's for heating or electricity generation or both), it would not be FERC's job to pick between the projects or to reject a proposal because of concerns about potential future stranded costs to the pipelines. Nor is it FERC's role to assess how either or both projects could impact meeting the region's climate goals

It is worth noting that FERC, spear-headed by Commissioner Cheryl LaFleur (who comes from New England), is considering ways to improve it gas pipeline siting process.